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DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA-2006-23998; Notice 2]

Pipeline Safety: Grant of Waiver; Rockies Express Pipeline

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.

ACTION: Grant of Waiver.

SUMMARY: PHMSA is granting Rockies Express Pipeline, L.L.C. (Rockies Express) a waiver of compliance from the pipeline safety regulation that prescribes the design factor to be used in the design formula for steel pipe. This waiver allows the Rockies Express pipeline to operate at hoop stresses up to 80 percent of the specified minimum yield strength (SMYS) in Class 1 locations. The waiver also grants Rockies Express relief from equipment requirements for pressure relieving and limiting stations.

Before granting the waiver, PHMSA performed a thorough technical review of Rockies Express's application and supporting documents. PHMSA requested and received supplementary information pertaining to numerous technical aspects of its metallurgy, pipeline design, and engineering practices. These materials are available in the docket PHMSA-2006-23998 at http://dms.dot.gov. PHMSA also sought comments from the public and received positive feedback from the impacted States along the pipeline and the Technical Pipeline Safety Standards Committee.

The waiver is subject to and conditional upon supplemental safety criteria set forth in this notice. The supplemental safety criteria address the life cycle management of the subject pipeline and require Rockies Express to adhere to maintenance, inspection, monitoring, control, and reporting standards exceeding existing regulatory requirements.

SUPPLEMENTARY INFORMATION:

Background

Rockies Express is a joint development of Kinder Morgan Energy Partners, L.P. and Sempra Pipelines & Storage, a subsidiary of Sempra Energy.

Rockies Express is obtaining regulatory approvals to construct a new 1,323-mile interstate natural gas pipeline. When it is complete, the 42-inch diameter pipeline will transport natural gas from basins in Colorado and Wyoming to markets in the upper Midwest and Eastern United States. The pipeline will cross portions of Wyoming, Colorado, Nebraska, Missouri, Illinois, Indiana, and Ohio.

Rockies Express plans to construct the pipeline in three phases. The first or western segment of the pipeline will be approximately 710 miles long. It will start at the hub in Cheyenne, Wyoming and extend to an interconnection with the Panhandle Eastern Pipe Line Company in Audrain County, Missouri. Four additional compressor stations will be installed at the Cheyenne Hub to support operations. The second or central segment of the pipeline will be approximately 425 miles long and extend from the terminus of the western segment of the pipeline in Audrain County, Missouri to the hub in Lebanon, Ohio. The final or eastern segment of the pipeline will be approximately 188 miles long and extend from the Lebanon Hub terminus to a point at or near Clarington, Ohio.

Rockies Express' Waiver Requests

Rockies Express requests a waiver of compliance from the following regulatory requirements:

49 CFR § 192.111 — Design Factor (F) for Steel Pipe; and

49 CFR § 192.201 — Required Capacity of Pressure Relieving and Limiting Stations.

The design factors are found in the following table:

Class Location	Design Factor (F)
1	0.72
2	0.60
3	0.50
4	0.40

The waiver request is for approximately 1,323 miles of 42-inch diameter pipe located within the United States. The waiver will allow Rockies Express to:

(1) Operate its new pipeline at hoop stresses up to 80 percent of SMYS in Class 1 locations, and at a maximum allowable operating pressure (MAOP) of 1,480 pounds per square inch gauge.

(2) Operate each pressure relief station installed to protect pipelines in Class 1 locations at pressures that may not exceed the MAOP plus 4 percent, or the pressure that produces a hoop stress of 83 percent of SMYS, whichever is lower at that time.

The pipe to be used for the Rockies Express pipeline will be either a longitudinal seam submerged arc welded pipe or a helical seam submerged arc welded pipe. The pipe also will be API Grades X80 and X70, and high-strength and high-toughness steel pipe, suitable for high-pressure gas transmission service. The Rockies Express pipeline will be 42 inches in diameter, coated externally with fusion-bonded epoxy (FBE), and be protected by an impressed current cathodic protection (CP) system. The field weld joints will be externally coated with field applied FBE.

All welds on the Rockies Express pipeline will be nondestructively tested. If any weld imperfections are discovered, they will be repaired or removed prior to putting the line in service. The Rockies Express pipeline also will be hydrostatically tested to a minimum of 100 percent of SMYS. Prior to commissioning the pipeline for gas service, it will be surveyed with a multi-channel geometry-smart-tool capable of detecting anomalies including dents and buckles. Approximately 90 percent of the Rockies Express pipeline will be located in Class 1 areas in a common right-of-way with other pipelines. Further, Kinder Morgan will install variable resistance bonds between the various pipelines and metallic structures sharing the right-of-way to eliminate stray electrical currents, and to equalize the voltage potentials between Rockies Express and other underground metallic structures.

Kinder Morgan conducted a risk analysis for Rockies Express and compared the risks associated with using a 0.80 design criteria to using a 0.72 design criteria. The risk analysis considered risks in the following nine areas: (1) stress corrosion cracking; (2) manufacturing defects; (3) weather/outside factors; (4) welding and fabrication defects; (5) equipment failure; (6) equipment impact or third-party damage; (7) external corrosion; (8) internal corrosion; and (9) incorrect operation.

From the risk analysis results Kinder Morgan determined that there was no significant increase in the overall risk associated with using the 0.80 design criteria for this type of pipe. Moreover, according to Kinder Morgan, only in the areas of external corrosion, internal corrosion, and incorrect operation did the risk analysis show a slightly higher degree of risk associated with using a 0.80 design factor. A pipe wall designed with a 0.80 design factor results in a slightly higher risk factor because it is manufactured with a thinner wall pipe than the pipe designed with a 0.72 design factor; therefore, the pipe designed with a 0.80 design factor operates at higher stress levels. Consequently, the factor of safety between the MAOP and the pipe’s SMYS is reduced. Rockies Express indicated that they will employ several control and prevention programs to mitigate these increased risks.

Grant of Waiver

PHMSA considered Rockies Express' waiver request and whether its proposal will yield an equivalent or greater degree of safety than the current regulations. PHMSA published a notice of intent to consider the waiver and solicited comments on March 22, 2006 (71 FR 14573). No comments were received.

Based on the Rockies Express' application for waiver for its new pipeline and PHMSA's extensive technical analysis and favorable feedback from the impacted States and the Technical Pipeline Safety Standards Committee, PHMSA hereby grants Rockies Express' waiver request with the following supplemental safety criteria:

Pipe and Material Quality

1. Steel Properties: The skelp/plate must be micro alloyed, fine grain, fully killed steel with calcium treatment and continuous casting.

2. Manufacturing Standards: The pipe must be manufactured according to American Petroleum Institute (API) standard 5L, product specification level (PSL) 2, and supplementary requirements (SR) for maximum operating pressures and minimum operating temperatures. Pipe carbon equivalents must be at or below 0.25 based on the material chemistry parameter (Pcm) formula.

3. Fracture Control: The API standard 5L and other standards address steel pipe toughness properties needed to resist initiation and propagation, and arrest (stop) a pipeline failure caused by a fracture. Rockies Express must institute an overall fracture control plan addressing steel pipe properties necessary to resist and arrest this condition within 6 pipe joints. The plan must include acceptable Charpy Impact and Drop Weight Tear Test values, which are measures of a steel pipeline's toughness and resistance to fracture.

The fracture control plan must also be in accordance with API standard 5L, Appendix F and must include the following tests:

- (a) SR 5A- Fracture Toughness Testing for Shear Area: Test results must be at least 80 percent of the minimum average shear area for all heats with a minimum result of 80 percent shear area for any single test;
- (b) SR 5B – Fracture Toughness Testing for Absorbed Energy; and
- (c) SR 6 – Fracture Toughness Testing by Drop Weight Tear Test: Test results must be at least 80 percent of the average shear area for all heats with a minimum result of 60 percent of the shear area for any single test.

The above fracture initiation, propagation and arrest plan must account for the entire range of pipeline operating temperatures, pressures and gas compositions planned for the pipeline diameter, grade, and operating stress level associated with this wavier.

4. Steel Plate Quality Control: The steel mill and/or pipe rolling mill must incorporate a comprehensive plate/coil mill and pipe mill inspection program to check for defects and inclusions that could affect the pipe quality. This program must include a plate (body and all ends) ultrasonic testing (UT) inspection program to check for imperfections such as laminations.

> An inspection protocol for centerline segregation evaluation using a test method referred to as slab macro-etching must be employed to check for inclusions that may form as the steel plate cools after it has been cast. A minimum of one macro-etch test must be performed from the first heat (manufacturing run) of each sequence (approximately 4 heats) and graded on the Mannesmann scale or equivalent. Test results with a Mannesmann scale rating of one or two out of a possible five are acceptable.

5. Pipe Seam Quality Control: A quality assurance program must be instituted for pipe weld seams. The pipe weld seam tests must meet the minimum requirements for tensile strength in API standard 5L for the appropriate pipe grade properties.

> A pipe weld seam hardness test using the Vickers hardness testing of a cross-section from the weld seam must be performed on one length of pipe from each heat. The maximum weld seam and heat affected zone hardness must be a maximum of 280 Vickers hardness. The hardness tests must include a minimum

of 3 readings for each heat affected zone, 3 readings in the weld metal, and 2 readings in each section of pipe base metal for a total of 13 readings.

The pipe weld seam must be 100 percent ultrasonically tested after expansion and hydrostatic testing per APL standard 5L.

6. Puncture Resistance: Steel pipe will be puncture resistant to 35 ton. Puncture resistance will be calculated based on industry established calculations such as the Pipeline Research Council International's "Reliability Based Prevention of Mechanical Damage to Pipelines" calculation method.

7. Mill Hydrostatic Test: The pipe must be subjected to a mill hydrostatic test pressure of 95 percent SMYS or greater for 10 seconds.

8. Pipe Coating: The application of a corrosion resistant coating to the steel pipe must be subject to a coating application quality control program. The program must address pipe surface cleanliness standards, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, minimum coating thickness, coating imperfections, and coating repair.

9. Field Coating: A field girth weld joint coating application specification and quality standards to ensure pipe surface cleanliness, application temperature control, adhesion quality, cathodic disbondment, moisture permeation, bending, minimum coating

thickness, holiday detection, and repair quality must be implemented in field conditions. Field joint coatings must be non-shielding to CP. Field coating applicators must use valid coating procedures and be trained to use these procedures.

10. Coatings for Trenchless Installation: Coatings used for directional bore, slick bore, and other trenchless installation methods must resist abrasions and other damages that may occur due to rocks and other obstructions encountered in this installation technique.

11. Bends Quality: Certification records of factory induction bends and/or factory weld bends must be obtained and retained. All bends, flanges, and fittings must have carbon equivalents (CE) below 0.42 or a pre-heat procedure prior to welding for CE above 0.42.

12. Fittings: All pressure rated fittings and components (including flanges, valves, gaskets, pressure vessels, and compressors) must be rated for a pressure rating commensurate with the MAOP and class location of the pipeline. Designed fittings (including tees, elbows and caps) must have the same design factors as the adjacent pipe class location.

13. Design Factor – Stations: Compressor and meter stations must be designed using a design factor of 0.50 in accordance with § 192.111.

14. Temperature Control: The compressor station discharge temperature must be limited to 120° Fahrenheit or a temperature below the maximum long-term operating temperature for the pipe coating.

15. Overpressure Protection Control: Mainline pipeline overpressure protection must be limited to a maximum of 104 percent MAOP.

16. Welding Procedures: Automated or manual welding procedure documentation must be submitted to the appropriate PHMSA regional office. The PHMSA's regional office must be notified within 14 days before welding procedure qualification activities.

17. Depth of Cover: The soil cover must be a minimum of 36 inches except in areas where threats from chisel plowing or other activities require the top of the pipeline to be installed one foot below the deepest penetration.

Construction

18. Construction Quality: A construction quality assurance plan to ensure quality standards and controls must be maintained throughout the construction phase with respect to: inspection, pipe hauling and stringing, field bending, welding, non-destructive examination (NDE) of girth welds, field joint coating, pipeline coating integrity tests, lowering of the pipeline in the ditch, padding materials to protect the pipeline, backfilling, alternating current (AC) interference mitigation and CP

systems. All girth welds must be non-destructively examined by radiography or alternative means. The NDE examiner must have all required certifications that are current.

19. Interference Currents Control: Control of induced AC from parallel electric transmission lines and other interference issues that may affect the pipeline must be incorporated into the design of the pipeline and addressed during the construction phase. Issues identified and not originally addressed in the design phase must be brought to PHMSA's attention. An induced AC program to protect the pipeline from corrosion caused by stray currents must be in place within six months after placing the pipeline in service.

Pre-In Service Hydrostatic Pressure Test

20. Test Level: The pre-in service hydrostatic test must be to a pressure producing a hoop stress on 0.8 designed class 1 pipe of at least 100 percent SMYS and 1.25 X MAOP.

21. Assessment of Test Failures: Any pipe failure occurring during the pre-in service hydrostatic test must undergo a root cause failure analysis to include a metallurgical examination of the failed pipe. The results of this examination must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the appropriate PHMSA regional office.

Supervisory Control and Data Acquisition (SCADA)

22. SCADA System Capabilities: A SCADA system to provide remote monitoring and control of the entire pipeline system must be employed.

23. Mainline Valve Control: Mainline valves that reside on either side of pipeline segment containing a High Consequence Area (HCA) where personnel response time to the valve exceeds one (1) hour must be remotely controlled by the SCADA system. The SCADA system must be capable of opening and closing the valve and monitoring the valve position, upstream pressure and downstream pressure. As an alternative, a leak detection system for mainline valve control is acceptable.

24. SCADA Procedures: A detailed procedure for establishing and maintaining accurate SCADA set points must be established to ensure the pipeline operates within acceptable design limits at all times.

Operations and Maintenance

25. Leak Reporting: Rockies Express must notify the appropriate PHMSA regional office within 24 hours of any non- reportable leaks occurring on the pipeline.

26. Annual Reporting: Following approval of the waiver, Rockies Express must annually report the following:
    - The results of any in-line inspection (ILI) or direct assessment results performed within the waiver area during the previous year;

- Any new integrity threats identified within the waiver area during the previous year;
- Any encroachment in the waiver area, including the number of new residences or public gathering areas;
- Any reportable incidents associated with the waiver area that occurred during the previous year;
- Any leaks on the pipeline in the waiver area that occurred during the previous year;
- A list of all repairs on the pipeline in the waiver area made during the previous year;
- On-going damage prevention initiatives on the pipeline in the waiver area and a discussion of their success; and
- Any company mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the company operating the pipeline to which this waiver applies.

27. Pipeline Inspection: The pipeline must be capable of passing ILI. All headers and other segments covered under this waiver that do not allow the passage of an ILI device must have a corrosion mitigation plan.

28. Gas Quality Monitoring and Control: An acceptable gas quality monitoring and mitigation program must be instituted to not exceed the following limits:

    a. H_2S (4 grains maximum);

b. CO_2 (3 percent maximum);

c. H_2O (less than or equal to 7 pounds per million standard cubic feet and no free water); and

d. Other deleterious constituents that may impact the integrity of the pipeline must be instituted.

Filters/separators must be installed at locations where gas is received into the pipeline to minimize the entry of contaminants and to protect the integrity of downstream pipeline segments.

Gas quality monitoring equipment must be installed to permit the operator to manage the introduction of contaminants and free liquids into the pipeline.

29. Cathodic Protection: The initial CP system must be operational within 12 months of placing the pipeline in service.

30. Interference Current Surveys: Interference surveys must be performed within six months of placing the pipeline in service to ensure compliance with applicable NACE International (NACE) standards (Recommended Practice (RP) 0169 and RP 0177) for interference current levels.

31. Corrosion Surveys: Corrosion surveys of the affected pipeline must be completed within six months of placing the respective CP system(s) in operation to ensure

CP (in accordance with the NACE standard RP 0169, paragraphs 6.2 and 6.3), test stations, AC interference mitigation, and AC grounding programs (NACE standard RP 0177) are being implemented along the pipeline.

32. Verification of Cathodic Protection: A close interval survey (CIS) must be performed in concert with ILI in accordance with subpart O reassessment intervals for all HCA pipeline mileage. If any annual test point readings fall below subpart I requirements, remediation must be performed and must include a CIS on either side of the affected test point to ensure corrosion control.

33. Pipeline Markers: Rockies Express must employ line-of-sight markings on the pipeline in the waiver area except in agricultural areas, subject to Federal Energy Regulatory Commission permits or environmental permits and local restrictions.

34. Pipeline Patrolling: Pipeline patrolling must be conducted at least monthly to inspect for excavation activities, ground movement, wash-outs, leakage, and/or other activities and conditions affecting the safe operation of the pipeline.

35. Monitoring of Ground Movement: An effective monitoring/mitigation plan must be in place to monitor for and mitigate issues of unstable soil and ground movement.

Integrity Management

36. Review of Risk Assessment Calculations: A copy of the C-FER PIRAMID risk analysis report regarding the pipe subject to this waiver must be submitted to PHMSA Headquarters.

37. Initial ILI: A baseline ILI must be performed in association with the construction of the pipeline using a high-resolution Magnetic Flux Leakage (MFL) tool within three years of placing a pipeline segment in service. A geometry tool must be launched either prior to placing the pipeline in service, or no later than six months after placing the pipeline in service.

38. Future ILI: A second high-resolution MFL inspection must be performed and completed on the pipe subject to this waiver within the first reassessment interval required by subpart O, regardless of HCA classification. Future ILI must be performed on a frequency consistent with subpart O for the entire pipeline covered by this waiver.

39. Direct Assessment Plan: Headers, mainline valve bypasses, and other sections covered by this waiver that cannot accommodate ILI tools must be part of a Direct Assessment (DA) plan or other acceptable integrity monitoring method.

40. Initial CIS: A CIS must be performed on the pipeline within one year of completion of the installation of CP systems. The CIS results must be integrated with the baseline ILI to determine whether further action is needed.

41. Damage Prevention Program: Common Ground Alliance's damage prevention best practices must be incorporated into the Rockies Express damage prevention program.

42. Class 2 and 3 Pipe: Pipe installed in Class 2 and Class 3 locations must use stress factors of 0.60 and 0.50 as required in §192.111. Pipe in road and railroad crossings must meet the requirements of §192.111.

43. Anomaly Evaluation and Repair: Anomaly evaluations and repairs must be performed based upon the following:

- <u>Anomaly Response Time</u>
    - Any anomaly with a failure pressure ratio (FPR) equal to or less than 1.1 must be treated as an "immediate" per subpart O.
    - Any anomaly with an FPR equal to or less than 1.25 must be remediated within 12 months per subpart O.
    - Any anomaly with an FPR greater than 1.25 must have a remediation schedule per subpart O.

- <u>Anomaly Repair Criteria</u>
    - Segments operating at MAOP equal to 80 percent stress level - any anomaly evaluated and found to have an FPR equal to or less than 1.25 must be repaired.
    - Segments operating at MAOP equal to 66 percent stress level - any anomaly evaluated and found to have an FPR equal to or less than 1.50 must be repaired.
    - Segments operating at MAOP equal to 56 percent stress level - any anomaly evaluated and found to have an FPR equal to or less than 1.80 must be repaired.

a. All other pipe segments with anomalies not repaired must be reassessed according to subpart O and the American Society of Mechanical Engineers (ASME) standard B31.8S requirements. Each anomaly not repaired must have a corrosion growth rate and ILI tool tolerance assigned to it per the Gas Integrity Management Program (IMP) to determine the maximum re-inspection interval.

b. Rockies Express must confirm the remaining strength (R-STRENG) effective area method, R-STRENG - 0.85dL, and ASME standard B31G assessment methods are valid for their pipe diameter, wall thickness, grade, operating pressure, operating stress level, and operating temperature. If it is not valid, Rockies Express must confirm a valid evaluation method to PHMSA. Until confirmation of the previously mentioned anomaly assessment calculations has been performed, Rockies

Express must use the most conservative of the calculations for anomaly evaluation.

c. Dents must be evaluated and repaired per §192.309(b)(ii) and §192.933(d)(l)(ii).

44. Preliminary Criteria Reporting: A preliminary report describing the results, completion dates and status of the supplementary requirements must be completed for the western and eastern segments of the pipeline and submitted to PHMSA Headquarters and the appropriate PHMSA regional office prior to commencing construction of each segment.

45. Criteria Completion Reporting: A report describing results, completion dates and status of the outstanding supplementary requirements must be submitted to PHMSA Headquarters and the appropriate regional office within 180 days after completion of the western pipeline segment. A similar report must be completed within 180 days of completion of the eastern segment and submitted to PHMSA Headquarters and the appropriate PHMSA regional office.

A follow-up report must be submitted for the western and eastern segments after the baseline ILI run has been performed with assessment and integration of the results. A final report must be submitted upon completion of the second ILI run for the western and eastern segments. These reports must be submitted to PHMSA Headquarters and the appropriate PHMSA regional office.

46. Potential Impact Radius Calculation Updates: If the pipeline operating pressures and gas quality are determined to be outside the parameters of the C-FER Study, a new study with the uprated parameters must be incorporated into the IMP.

If at anytime PHMSA determines the effect of the waiver is inconsistent with pipeline safety, PHMSA will revoke the waiver at its sole discretion.

AUTHORITY: 49 U.S.C. 60118 (c) and 49 CFR § 1.53.

Issued in Washington, DC on ______________________.

Theodore L. Willke,

Deputy Associate Administrator for Pipeline Safety.